IRONHORSE
OIL & GAS INC.

Annual Report
2007

HIGHLIGHTS

Year ended December 31,	2007	2006	% Change
Daily production:			
Natural Gas (thousand cubic feet)	**3,977**	1,162	+242
Oil and NGLs (barrels)	**7.2**	8.2	-12
Boe (barrels oil equivalent)	**670.0**	201.9	+232
Financial:			
Petroleum and Natural Gas Revenue ($)	**9,032,888**	2,709,734	+233
Funds flow from operations ($)	**3,529,537**	1,049,728	+236
Net income (loss) ($)	**(812,145)**	(732,821)	-11
Capital expenditures ($)	**12,406,475**	13,913,779	-11
Total assets ($)	**25,842,943**	16,848,830	+53
Working capital (deficiency) ($)	**(7,983,328)**	(4,337,357)	-84
Per diluted share amounts:			
Funds flow from operations ($/share)	**0.176**	0.059	+198
Net income ($/share)	**(0.042)**	(0.045)	+7
Number of shares outstanding:			
Basic weighted average	**19,411,224**	16,346,171	+19
Diluted weighted average	**20,034,128**	17,733,837	+13
End of Period	**19,476,809**	17,067,392	+14

Highlights:

- 2007 production increased 232% to 670 boe/d due to the successful drilling and tieing-in of 25 natural gas wells at Shackleton
- With increased production and higher Company realized commodity prices, funds flow from operations for 2007 was up by 236% to $3.5 million
- Based on capital expenditures of $12.4 million, finding and development costs for 2007 were $8.21 per boe after accounting for positive reserve revisions and reduced future development costs
- Due to ownership of infrastructure and increased production at Shackleton, production expenses were reduced by 23% to average $3.32 in 2007
- General and administration costs were lower by 7% at $3.64 per boe due to increased production in 2007
- Successful completion in January 2007 of private placement of 2,718,750 common shares for proceeds of $5.8 million

MANAGEMENT DISCUSSION AND ANALYSIS

Management discussion and analysis of the financial condition and results of operations of Ironhorse Oil & Gas Inc. ("Ironhorse" or the "Company") should be read in conjunction with the Company's audited financial statements and related notes for the years ended December 31, 2007 and 2006. Additional information about Ironhorse, its operations and history including the Company's Annual Information Form may be found as filed on the System for Electronic Data Analysis and Retrieval at www.sedar.com. The calculation of barrels of oil equivalent ("boe") is based on a relative energy content conversion ratio of six thousand cubic feet ("mcf") of natural gas to one barrel of oil when measured at the burner tip. Production volumes reported are the Company's interest before royalties, and all amounts are expressed in Canadian dollars unless otherwise stated. This discussion and analysis may contain forward-looking information that is subject to known and unknown risks, uncertainties and other factors. Readers are cautioned that actual future results, performance or achievements may be different from those expressed or implied and the difference may be material.

Non-GAAP Measures

The financial data presented has been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP") except for the term "funds flow from operations". Funds flow from operations has been presented for information purposes only and should not be considered an alternative to, or more meaningful than cash flow from operating activities as determined in accordance with GAAP. The determination of the Company's funds flow from operations may not be comparable to the same reported by other companies. Funds flow from operations refers to net income from the statement of operations plus non-cash expenses, less abandonment costs incurred, and excludes the change in non-cash operating working capital for the period. Funds flow from operations per share was calculated using fully diluted weighted average shares outstanding at year-end.

Disclosure Controls and Internal Controls for Financial Reporting

The Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of the Company's disclosure controls and procedures and concluded that these disclosure controls and procedures were effective as of December 31, 2007 and in respect of the year then ended.

The Chief Executive Officer and Chief Financial Officer concluded that the design of internal control over financial reporting was effective as at December 31, 2007 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. As Ironhorse has limited segregation of duties amongst its staff, it relies on key individuals as an integral part of this control process.

Critical Accounting Estimates

A summary of the Ironhorse's significant accounting policies is contained in Note 2 to the audited financial statements. These policies are subject to estimates and judgments about future events, many of which may beyond the control of management. The following is a discussion of the accounting estimates that are critical to preparation of the financial statements.

Depletion and depreciation expense is based on the amortization of net capitalized costs less unproved property costs plus future development costs for oil and natural gas exploration and development activities using the unit-of-production method. This method of cost amortization is based on the ratio of oil and natural gas sales production to estimated proved oil and natural gas reserves. The evaluation of estimated proved oil and natural gas reserves is prepared by independent petroleum consultants and reviewed by the Company's Reserves Committee of the Board of Directors. The process of estimating proved reserves involves professional judgment and a significant number of assumptions and decisions based on available geological, geophysical, production and economic data. Reserves estimates and future development costs change over time based on development and production activities and changing economic conditions. Unproved property costs are reviewed by management on a quarterly basis to determine if they should no longer be excluded from the cost base for amortization when proved reserves have been established or if the properties have become impaired. Changes to any of the aforementioned estimates could affect depletion and depreciation expense.

The Company's future asset retirement obligation is a fair value determination based the present value of estimated costs and anticipated future timing to complete the abandonment and reclamation of Ironhorse's interest in wells and facilities. Cost estimates associated with abandonment and reclamation require judgment concerning the method, timing and extent of future retirement activities. The present value calculations, which give rise to accretion expense adjustments each quarter of the year, are based on management's estimate of the Company's credit-adjusted risk-free interest rate. The future obligation and current accretion expense are subject to revision based on changes in technology, abandonment timing, reclamation costs, discount rates and the regulatory environment.

Stock options issued under the Company's stock option plan are accounted for using the fair value method. Stock-based compensation cost is determined on the date of an option grant using the Black-Scholes option pricing model, which requires the estimation of several variables including volatility in Ironhorse share prices, expected life of the option and the risk-free interest rate. Changes to these estimates would alter the valuation of the option granted and its related charge to stock-based compensation expense.

Business Environment and Risks

Ironhorse is directly affected by commodity price fluctuations, particularly on sales volumes that the Company has not hedged. For the year ended December 2007, natural gas production accounted for 99% of total Company production when measured on a Boe basis. In 2007, average annual Canadian natural gas prices were slightly down from 2006, while average annual oil prices increased about 5% over 2006 levels.

	Q4 '07	Q3 '07	Q2 '07	Q1 '07	Q4 '06	Q3 '06	Q2 '06	Q1 '06
NYMEX prompt month for West Texas Intermediate crude oil (US$/bbl)	$90.73	$75.33	$64.99	$58.24	$57.75	$70.66	$70.67	$63.26
Edmonton posted reference for crude oil (C$/bbl)	86.79	80.26	72.40	67.16	65.07	79.23	78.34	68.91
NYMEX prompt month for Henry Hub natural gas (US$/mmbtu)	7.37	6.24	7.64	7.17	7.26	6.13	6.70	7.85
AECO-C Spot price for natural gas (C$/mcf)	6.19	5.22	7.10	7.37	6.91	5.71	6.07	7.53

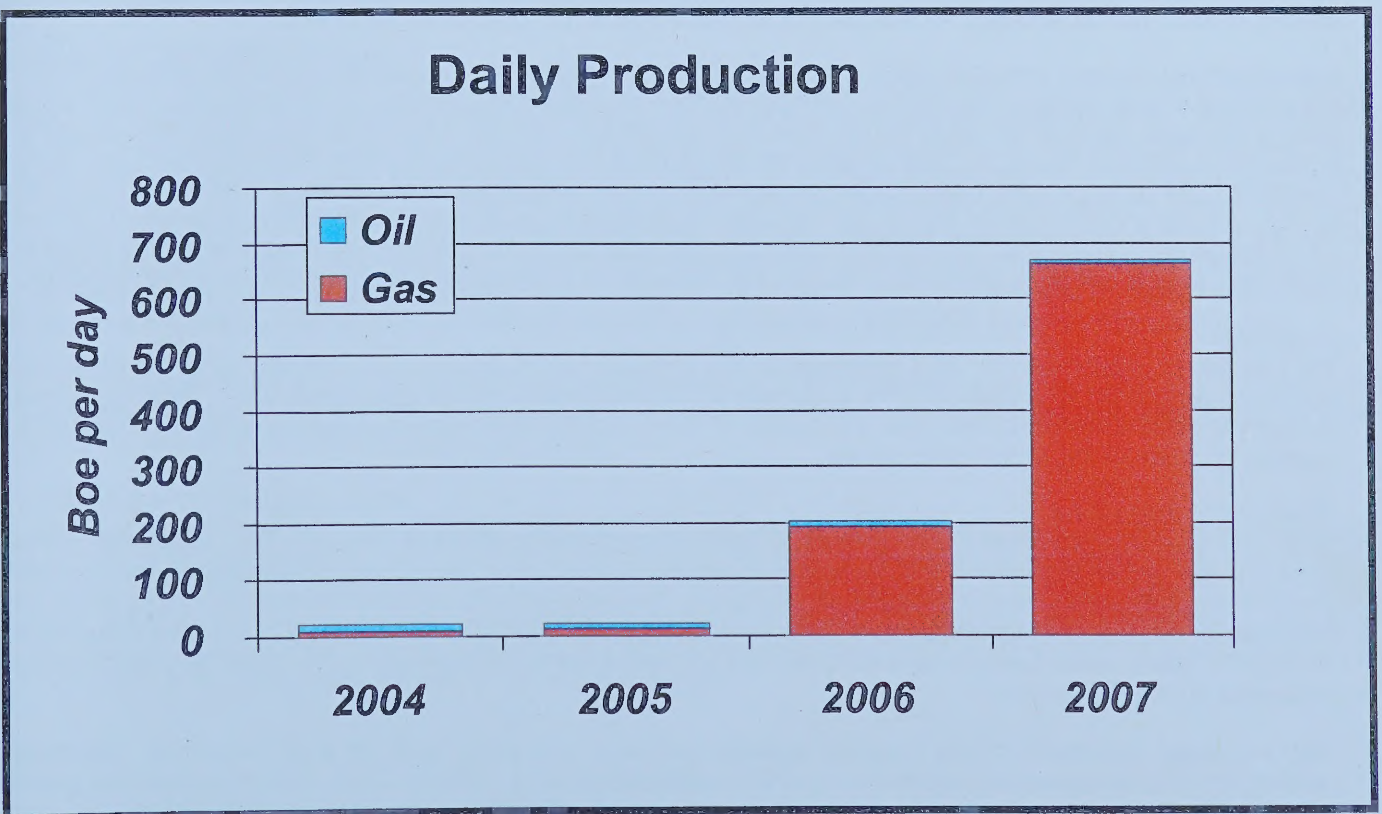
To counter the risks of natural gas price fluctuations, and its effects on the ability of Ironhorse to maintain cash flow for capital investment purposes, management may enter into short-term fixed price or costless collar natural gas sales contracts.

The province of Alberta announced comprehensive changes to the crown royalties charged on petroleum sales effective January 1, 2009. If implemented as announced, a significant reduction could occur in industry activity in Alberta. Corporate interests at Pembina will be negatively affected by the implementation of the proposed royalty program. Industry continues to have ongoing dialogue with government representatives to outline consequences, which will have a serious affect on the exploration and development of higher productivity oil reservoirs, like those found in Pembina. Currently, virtually all of the Company's production comes from the Shackleton property in Saskatchewan.

Besides commodity price risk, the Company faces technical and operational risks and competition with other corporations with more financial and staffing resources. The Company will attempt to mitigate some of these risks by employing prudent financial practices, and concentrating on core areas where staff skills can be focused and a meaningful interest can be acquired and managed.

Selected Annual Operating Data

Year ended December 31,	**2007**	2006	2005
Production			
Natural gas (mcf)	**1,451,435**	424,091	25,907
Crude oil and natural gas liquids (barrels)	**2,629**	3,002	3,921
Barrels of oil equivalent (Boe)	**244,535**	73,684	8,239
Boe per day	**670**	202	23
Financial			
Revenue	**$9,032,888**	$2,709,734	$493,616
Operating netback	**4,810,805**	1,300,631	282,252
Funds flow from operations	**3,529,537**	1,049,728	193,753
Net income (loss)	**(812,145)**	(732,821)	335,476
Basic and diluted net income (loss) per share	**$(0.04)**	$(0.04)	$0.03
Capital expenditures	**12,406,475**	13,913,779	3,434,941
Working capital (deficiency)	**(7,983,328)**	(4,337,357)	3,475,317
Total assets as at year-end	**25,842,943**	16,848,830	7,524,256
Financial and operations measures			
Price per mcf	**$6.09**	$5.92	$9.56
Price per barrel	**$71.06**	$66.18	$62.72
Price per boe	**$36.94**	$36.78	$59.91
Royalty rate	**37.8%**	40.3%	24.8%
Operating costs per boe	**$3.32**	$4.30	$10.79
General and administration per boe	**$3.64**	$3.91	$16.85



Operations

Production

After a successful drilling program in the first quarter of 2007, Ironhorse added 25 natural gas wells for a total of 32 producing wells in the Shackleton area of southwestern Saskatchewan. Production in 2007 averaged 3,977 thousand cubic feet per day ("mcf/d") compared to 1,162 mcf/d in 2006 as a result of the increased number of producing wells. After completion of the successful drilling program in the first quarter of 2007, Ironhorse production peaked at 900 boe/d. Due to natural declines in production from the Shackleton field, corporate daily production in the last quarter of 2007 was 664 boe/d compared to 748 boe/d in the third quarter of the year. While virtually all production comes from the Company's 50% working interest in the Shackleton field, the Company also produced 15 boe/d of oil and natural gas production from small interests in two separate fields in Alberta. The level of production from these minor area locations has not declined significantly over the course of 2007.

Revenue

Natural gas prices, as referenced at AECO, were down 1% for the year to average $6.47 per mcf, and up 19% over the third quarter of 2007 to average $6.19 per mcf for the last quarter of 2007. The posted price for crude oil at Edmonton averaged $76.65 per barrel for the year, up 5% from 2006 and $86.79 per barrel for the last quarter of 2007, an increase of 8% over the third quarter of the year.

Realized prices for 2007 averaged $6.09 per mcf and $71.06 per barrel for crude oil and NGLs, a 3% increase and a 7% increase, respectively, over commodity prices realized in 2006. The improved Company wellhead price for natural gas compared to the relative change in the AECO reference price is due to the execution of costless collar physical natural gas sales contracts. One contract was in place from November 1, 2006 to March 31, 2007 with a floor price of $8.00 per gigajoule ("GJ") and a ceiling price of $11.10 per GJ. Effective from April 1, 2007 to March 31, 2008, Ironhorse entered into another costless collar physical natural gas contract with a floor price of $7.00 per GJ and a ceiling price of $9.42 per GJ. For conversion purposes, one GJ approximates the energy derived from 0.99 mcf of natural gas from the Company's Shackleton property.

With increased prices and record production, revenue for the year was $9.0 million compared to $2.7 million in 2006. During the fourth quarter of 2007, revenue amounted to $2.2 million, relatively unchanged from the third quarter of 2007 due to stronger natural gas prices offsetting normal production declines.

Subsequent to year-end, management entered into additional physical term natural gas sales contracts. Covering the summer season running from April 1, 2008 to October 31, 2008, the Company has entered into a fixed price natural gas sales contract for 2000 GJ per day at $7.05 per GJ. For the next winter heating season covering November 1, 2008 to March 31, 2009, Ironhorse has entered into two costless collar physical natural gas sales contracts. One contract is for 1,000 GJ per day based on a floor price of $7.75 per GJ and a ceiling price of $9.45 per GJ. The other contract is for 500 GJ per day with a floor price of $8.00 per GJ and a ceiling price of $10.00 per GJ. Management will continue to monitor the natural gas sales price markets and may enter into similar physical short-term natural gas sales contracts to protect the company from commodity price volatility and downside risk.

Royalties

The Company's royalty rate for 2007 averaged 37.8% compared to 40.3% in 2006. Virtually all of the decline is due to the acquisition in January 2007 of a 2% overriding royalty on the Shackleton production. With the strong recovery in natural gas prices over the last quarter of 2007, royalty rates have increased to 37.4% in the fourth quarter, up from 34.3% in the third quarter.

Production Expenses

During the year, operating costs averaged $3.32 per boe compared to $4.30 per boe in 2006. Ownership of the plant and gas gathering systems, and improved capacity utilization have led to industry benchmark low costs of production and the improvement in year over year costs. Costs did increase significantly from $2.49 per mcf in the third quarter to $4.29 per mcf in the fourth quarter of 2007 due to reduced production being processed though the Shackleton plant, while costs to operate the plant did not decline, and annual lease rental payments being processed during the quarter.

With increased commodity prices, reduced royalties and lower operating costs, on a per boe basis, operating netback for 2007 increased to $4.8 million, a 270% increase from$1.3 million in 2006. Higher natural gas prices offset by the decline in production together with a higher royalty rate and increased production costs meant that the operating netback declined by 10% to $1.1 million.

Selected Quarterly Operating Data

	Q4 '07	Q3 '07	Q2 '07	Q1 '07	Q4 '06	Q3 '06	Q2 '06	Q1 '06
Production								
Natural gas (mcf)	361,918	407,360	457,755	224,402	129,664	177,677	110,880	5,870
Crude oil and natural gas liquids (barrels)	746	899	539	445	681	717	787	817
Barrels of oil equivalent (boe)	61,066	68,792	76,832	37,845	22,292	30,330	19,267	1,795
Boe per day	664	748	844	421	242	330	212	20
Financial								
Revenue	$2,226,934	$2,168,909	$3,121,154	$1,515,891	$975,898	$985,517	$646,935	$101,384
Operating netback	1,133,278	1,254,125	1,698,334	725,068	523,475	435,233	289,586	52,337
Funds flow from operations	737,590	893,995	1,325,542	572,410	388,414	394,680	210,953	55,681
Net income (loss)	(262,557)	(252,726)	(115,455)	(181,407)	(208,302)	(277,688)	(150,176)	(96,655)
Basic and diluted net income (loss) per share	$(0.01)	$(0.01)	$(0.01)	$(0.01)	$(0.01)	$(0.01)	$(0.01)	$(0.01)
Capital expenditures	$1,836,279	$243,804	$369,284	$9,957,108	$3,658,223	$238,628	$888,542	$9,128,386
Working capital (deficiency)	$(7,983,328)	$(7,231,714)	$(7,332,883)	$(7,966,037)	$(4,337,357)	$(1,764,724)	$(1,487,126)	$(5,585,987)
Assets at period end	$25,842,943	$25,271,324	$26,016,326	$27,108,010	$16,848,830	$14,664,181	$15,804,070	$14,906,433
Financial and operations measures								
Price per mcf	$6.11	$5.16	$6.74	$6.64	$7.22	$5.25	$5.31	$9.03
Price per barrel	$74.11	$73.68	$68.84	$58.54	$58.46	$73.52	$73.38	$59.23
Price per boe	$36.47	$31.53	$40.62	$40.06	$43.78	$32.49	$33.58	$56.48
Royalty rate	37.4%	34.3%	38.8%	41.3%	36.9%	43.4%	43.5%	23.2%
Operating costs per boe	$4.29	$2.49	$2.77	$4.37	$4.14	$4.06	$3.94	$14.21
G&A per boe	3.67	3.66	3.82	3.20	5.55	1.65	4.97	10.61

General and Administration

General and administration expense for 2007 amounted to $891 thousand or $3.64 per boe. Last year, general and administration expense was $288 thousand or $3.91 per boe. Ironhorse enjoys the benefits of a technical and administration services agreement with Grizzly Resources Ltd. ("Grizzly"), a private oil and gas company, which has common management with the Company. The Company is charged fees based on production and capital expenditures. The year-over-year increase in general and administration expense is due to increased fees from Grizzly as a result of higher production, increased staff costs for Company personnel and increasing corporate expenses. On a production basis, general and administration costs have declined to lower than industry average levels because of the significant increase in natural gas production in 2007. Despite the decline in production in the fourth quarter of 2007, general and administration expense on a boe basis were virtually unchanged.

Ironhorse capitalizes a portion of its general and administration costs that relate to exploration and development activities. During the year, $185 thousand was capitalized compared to the same amount in 2006 based on fees billed by Grizzly for capital investment activities.

Stock-based Compensation

During the year, 210,500 options (2006 – 264,000) were granted, 31,667 options (2006 – 95,834) were exercised and 222,999 options (2006 – nil) were cancelled. Due to the reduced number of unvested options outstanding during the year and lower stock price volatility for purposes of valuing new options granted, stock-based compensation expense for 2007 was $421,666 compared to $555,628 in 2006. Stock-based compensation expense for the last quarter of the year increased to $121,200, an increase from $64,916 in the third quarter as a result of new options granted during the last three months of 2007.

Interest

For the year ended December 31, 2007, interest expense amounted to $308 thousand compared to $12 thousand in 2006. The interest expense increase resulted from higher levels of bank debt during the year, resulting from increased credit use to help fund the Company's capital investment program. At December 31, 2007, total bank debt amounted to $6.9 million. Interest expense was $108 thousand for both the third and fourth quarters of 2007 as bank debt levels were relatively unchanged during these periods.

Depletion, Depreciation and Accretion

($)	Q4 '07	Q3 '07	Q2 '07	Q1 '07	Q4 '06	Q3 '06	Q2 '06	Q1 '06
Depletion and depreciation	972,695	1,207,978	1,366,717	659,635	537,872	683,264	221,724	7,597
Asset retirement accretion	9,268	13,893	8,480	22,484	1,112	2,854	2,906	3,081
Per boe	16.08	17.56	17.79	17.43	24.13	22.53	11.51	4.23

Depletion, depreciation and accretion expense ("DD&A") amounted to $4.3 million or $17.43 per boe in 2007 while the corresponding amounts in 2006 were $1.5 million or $19.82 per boe. The overall increase in total DD&A between years is due to higher production and a growing asset base subject to amortization. The reduction in DD&A on a boe basis is due to increased natural gas reserves being added at a lower relative cost when compared to prior periods. In particular, the DD&A rate per boe was $16.08 for the last quarter of 2007 compared to $17.76 for the third quarter, reflecting receipt of an updated reserve report at year-end, which recognized a significant upward revision on existing proved reserves not accounted for earlier in the year.

Capital expenditures

For the year ended December 31, 2007, Ironhorse invested $12.4 million compared to $13.9 million in 2006 according to the following categories:

($000s)	2007	2006
Land	$1,532	$2,391
Geological and geophysical	159	91
Drilling and completion	8,161	3,687
Facilities	2,554	7,745
Total capital expenditures	$12,406	$13,914

Land acquisition costs of $1.5 million were reduced from 2006 levels as lower acreage amounts were acquired in the Shackleton area in 2007 versus 2006. Seismic costs increased from $91 thousand in 2006 to $159 thousand in 2007 due to exploration efforts at Kotcho Lake in northeastern British Columbia. For the year ended December 31, 2007, drilling and completion costs amounted to $8.2 million. This was a 121% increase from 2006 expenditures due to development drilling at Shackleton, Saskatchewan and exploration drilling at Kotcho Lake, B.C. Coincident with development drilling at Shackleton was the expansion of existing plant and gas gathering infrastructure for a capital investment of $2.6 million in 2007.

($000s)	Q4 '07	Q3 '07	Q2 '07	Q1 '07	Q4 '06	Q3 '06	Q2 '06	Q1 '06
Shackleton	1,782	237	97	8,473	3,394	201	1,023	8,570
Pembina	4	12	20	32	5	38	124	558
N.E. British Columbia	50	(5)	252	1,452	1	-	-	-
Total	1,836	244	369	9,957	3,400	239	1,147	9,128

Shackleton

In the Shackleton area located in southwestern Saskatchewan, the Company holds a 50% interest in 11,788 acres of petroleum and natural gas rights, as well as the associated wells, gas gathering pipelines and plant facilities. In 2007, Ironhorse expanded its land base in the area by acquiring another 5,120 acres (2,460 net acres) to bring total land holdings in the area to 11,788 acres (5,894 net acres). During the year, the Company participated in the drilling of 31 natural gas wells. Twenty-nine wells were completed in 2007 with two remaining wells yet to be completed and tied-in. A plant expansion was completed in the first quarter of 2007 as new wells were brought on-stream at the end of the first quarter. In the fourth quarter of 2007, additional gas gathering pipelines were

installed in preparation for the 2007-2008 winter drilling program. Total capital invested in the Shackleton area amounted to $10.6 million or 85% of the total expended in 2007.

Pembina

At Pembina, in west central Alberta, Ironhorse holds an 18.75% interest in 4,960 acres of prospective undeveloped land in the area, which is actively being explored in the prolific Nisku oil horizon by other industry participants. Wells offsetting Company lands have tested at rates of 500 to 2,500 boe/d of light sour oil. During 2007, the focus has been on seismic evaluation of Company lands and those nearby. In 2008, Ironhorse is planning to apply for licences to drill two wells. Due to the nature of the light sour oil being produced from wells in this area, very detailed development plans with regulatory and community input need to be prepared in order to obtain drilling licences in this area. Ironhorse anticipates receipt of the drilling licences and beginning drilling operations in late 2008 or early 2009. Sixty-eight thousand dollars were expended in the Pembina area in 2007.

Kotcho Lake

Early in the year, Ironhorse farmed-in on a natural gas exploration play at Kotcho Lake in northeastern British Columbia. The Company also participated in the shooting of seismic over prospective nearby lands. The drilling of the farm-in well found non-commercial quantities of natural gas. Ironhorse currently has no plans for future investment in this area. In 2007, total funds expended in the Kotcho Lake area amounted to $1.7 million.

Petroleum and Natural Gas Reserves and Net Present Value

The following tables summarize the Company's remaining oil and natural gas reserve volumes along with the present value of future cash flows utilizing forecast pricing and cost estimates at December 31, 2007.

Reserves	**Natural Gas (mmcf)**	**Oil & NGLs (mbbl)**	**Boe (mboe)**
Proved Producing	5,583	19	950
Proved Undeveloped	5,729	-	955
Total Proved	11,312	19	1,905
Probable	3,616	6	608
Total Proved Plus Probable	14,928	25	2,513

Net Present Value Before Income Taxes			**Discounted at**		
($000s)	**0%**	**5%**	**8%**	**10%**	**12%**
Proved Producing	$21,418	$18,513	$17,123	$16,310	$15,574
Proved Undeveloped	16,409	12,361	10,564	9,559	8,680
Total Proved	37,827	30,874	27,687	25,869	24,254
Probable	14,772	9,220	7,218	6,222	5,423
Total Proved Plus Probable	$52,599	$40,094	$34,905	$32,091	$29,677

Net Present Value After Income Taxes			**Discounted at**		
($000s)	**0%**	**5%**	**8%**	**10%**	**12%**
Proved Producing	$18,640	$16,190	$15,015	$14,326	$13,703
Proved Undeveloped	9,418	6,792	5,618	4,961	4,385
Total Proved	28,058	22,982	20,633	19,287	18,088
Probable	8,523	5,429	4,295	3,725	3,264
Total Proved Plus Probable	$36,581	$28,411	$24,928	$23,012	$21,352

At December 31, 2007, GLJ Petroleum Consultants Ltd. completed an evaluation of the Company's petroleum and natural gas reserves and their associated cash flows. Despite using a slightly lower future natural gas price forecast for the 2007 report as compared to the 2006 report, the before tax net present value of cash flow for proved and probable reserves discounted at 10% was $32.1 million, an increase of $20.2 million from the prior year.

On a proved and probable basis, Ironhorse added 1.5 million boes of reserves in 2007. Of this amount, 7.3 billion cubic feet of natural gas, or 1.2 million boes, resulted from the 2007 drilling program at Shackleton plus 287 thousand additional boes were added due to positive reserve revisions to the Company's natural gas reserves at Shackleton.

With the inception-to-date investment at Shackleton being $23.4 million, and remaining future costs of $7.6 million to fully develop the booked proved and probable reserves, finding and development costs in this area now stand at $12.71 per boe (2006 - $14.30 per boe). Total Company finding and development costs for 2007, after accounting for reserve revisions and the decrease in future development costs, yielded $8.21 per boe (2006 - $16.50 per boe). Based on an operating netback of $14.43 per boe, the investment recycle ratio for 2007 was 1.76.

Reconciliation of Petroleum and Natural Gas Reserves Changes

	Year Ended December 31, 2007			Year Ended December 31, 2006		
	Oil & NGLs	**Natural Gas**	**Barrels Equivalent**	**Oil & NGLs**	**Natural Gas**	**Barrels Equivalent**
Proved reserves	(mbbls)	(mmcf)	(mboe)	(mbbls)	(mmcf)	(mboe)
Opening balance	21	5,519	941	28	243	69
Production	(3)	(1,451)	(245)	(3)	(424)	(74)
Revisions	1	1,279	215	(4)	10	(2)
Discoveries and extensions	–	5,965	994	–	5,690	948
Closing balance	19	11,312	1,905	21	5,519	941
Probable reserves						
Opening balance	6	1,863	316	4	40	11
Revisions	–	434	72	2	8	3
Discoveries and extensions	–	1,319	220	–	1,815	302
Closing balance	6	3,616	608	6	1,863	316
Proved plus probable reserves						
Opening balance	27	7,382	1,257	32	283	79
Production	(3)	(1,451)	(245)	(3)	(424)	(74)
Revisions	1	1,713	287	(2)	18	1
Discoveries and extensions	-	7,284	1,214	–	7,506	1,251
Closing balance	25	14,928	2,513	27	7,382	1,257

Taxation

At December 31, 2006, Ironhorse had approximately $20.3 million of tax pools and unused loss carry-forwards, as set out below. The Company does not expect to be taxable until 2009 at the earliest.

($000s)	**December 31, 2007**
Non-Capital Losses Carried Forward	**$ 218**
Canadian Exploration Expenses (CEE)	**202**
Canadian Development Expenses (CDE)	**4,036**
Canadian Oil and Gas Property Expenses (COGPE)	**5,483**
Undepreciated Capital Costs (UCC)	**10,333**
Share Issue Costs	**69**
Total	**$20,341**

Pursuant to the flow-through share component of the private placement equity issue that closed in January 2007, the Company committed to invest $2,175,000 on qualifying expenditures prior to the end of 2008. At December 31, 2007, Ironhorse had satisfied $1,010,000 of this commitment, and in the first quarter of 2008, another of $1,000,000 of qualifying expenditures was incurred. The remaining commitment to invest $165,000 on qualifying expenditures is expected to be fulfilled prior to December 31, 2008.

Liquidity and Capital Resources

In January 2007, the Company successfully completed a private placement of share equity where 2,718,750 common shares were issued for proceeds of $5.8 million. Funds from operations for 2007 generated $3.5 million, a 236% increase over the $1.0 million generated in 2006. Cash raised from operations and the share equity issue, together with advances of $5.1 million under the Company's bank credit facilities, funded Ironhorse's $12.4 million capital expenditure program in 2007.

At year-end, Ironhorse had a revolving production bank loan credit facility of $8.0 million, of which $6.9 million was drawn at December 31, 2007. To facilitate funding of the drilling program and plant expansion in the first quarter of 2008, the Company's bankers provided a additional $4.0 development credit facility.

During the year, the Company acquired 341,000 common shares at an average price of $1.60 per share pursuant to the terms of its normal course issuer bid. At December 31, 2007, the Company had 19,476,809 common shares outstanding (2006 – 17,067,392).

Outlook

In 2007, the Company profitably grew its production and reserves. Ironhorse continues to be a low cost producer with results being better than industry averages for finding and development costs and production expenses, in particular. For 2008, Ironhorse plans to continue to develop its properties at Shackleton and Pembina. In the first quarter of 2008, the Company successfully drilled and tied-in 31 new wells and expanded plant capacity to 17.5 million cubic feet per day at Shackleton. Plans are currently underway to obtain drilling licences for two wells in the Pembina area, which the Company anticipates could be drilled by the end of the year or early in 2009. Management continues to investigate and pursue opportunities to create additional shareholder value.

Dated: April 15, 2008

Kenway Mack Slusarchuk Stewart LLP
CHARTERED ACCOUNTANTS

Auditors' Report

To: The Shareholders of
Ironhorse Oil & Gas Inc.

We have audited the balance sheets of **Ironhorse Oil & Gas Inc.** as at **December 31, 2007 and 2006** and the statements of operations and deficit and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2007 and 2006, and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Kenway Mack Slusarchuk Stewart LLP
Chartered Accountants

March 13, 2008
Calgary, Alberta

220, 333 - 11 Avenue S.W., Calgary, AB, T2R 1L9 Tel: 403.233.7750 Fax: 403.266.5267 www.kmss.ca

IRONHORSE OIL & GAS INC.
Balance Sheets

	December 31 2007	December 31 2006
ASSETS		
Current Assets:		
Cash	**$ 44,518**	$ 8,674
Accounts receivable	**833,791**	398,766
Prepaid expenses	**47,579**	38,902
	925,888	446,342
Property and equipment (note 3)	**24,917,055**	16,402,488
	$ 25,842,943	$ 16,848,830
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 2,015,408**	$ 2,977,699
Revolving production bank loan (note 9)	**6,893,808**	1,806,000
	8,909,216	4,783,699
Asset retirement obligation (note 4)	**666,379**	323,037
Future income taxes (note 5)	**1,192,439**	788,701
	10,768,034	5,895,437
Shareholders' equity:		
Share capital (note 6)	**18,887,650**	14,093,637
Contributed surplus (note 6)	**993,804**	854,156
Deficit	**(4,806,545)**	(3,994,400)
	15,074,909	10,953,393
	$ 25,842,943	$ 16,848,830

See accompanying notes to the financial statements.

Approved on behalf of the board:

(signed) *"Larry J. Parks"*
Director – Larry J. Parks

(signed) *"Gerry C. Quinn"*
Director – Gerry C. Quinn

IRONHORSE OIL & GAS INC.
Statements of Operations and Deficit

	Year ended December 31 2007	Year ended December 31 2006
Revenue	**$ 9,032,888**	$ 2,709,734
Royalties	**(3,410,341)**	(1,092,481)
	5,622,547	1,617,253
Other income	**8,063**	57,319
	5,630,610	1,674,572
Expenses		
Operations	**811,742**	316,622
General and administration	**890,844**	288,466
Stock-based compensation	**421,666**	555,628
Interest	**308,337**	11,516
Depletion, depreciation and accretion	**4,261,150**	1,460,410
	6,693,739	2,632,642
Income (loss) before income taxes	**(1,063,129)**	(958,070)
Future income tax recovery (note 5)	**250,984**	225,249
Net income (loss)	**(812,145)**	(732,821)
Deficit, beginning of the year	**(3,994,400)**	(3,261,579)
Deficit, end of the year	**$ (4,806,545)**	$ (3,994,400)
Net income (loss) per share (note 7)		
Basic	**$ (0.04)**	$ (0.04)
Diluted	**$ (0.04)**	$ (0.04)

See accompanying notes to the financial statements.

IRONHORSE OIL & GAS INC.
Statements of Cash Flows

	Year ended December 31 2007	Year ended December 31 2006
Cash flows from operating activities:		
Net income (loss)	**$ (812,145)**	$ (732,821)
Add (deduct) items not affecting cash		
Depletion, depreciation and accretion	**4,261,150**	1,460,410
Future income tax recovery	**(250,984)**	(225,249)
Stock-based compensation	**357,416**	555,628
Abandonment costs incurred	**(25,900)**	(8,240)
Funds flow from operations	**3,529,537**	1,049,728
Changes in non-cash working capital (note 11)	**(278,005)**	(208,731)
	3,251,532	840,997
Cash flows from financing activities		
Increase in revolving production bank loan	**5,087,808**	1,806,000
Issuance of common shares	**5,771,628**	5,051,377
Exercise of stock options	**5,984**	
Repurchase of common shares	**(546,645)**	
	10,318,775	6,857,377
Cash flows from investing activities		
Expenditures on property and equipment	**(12,406,475)**	(13,913,779)
Changes in non-cash working capital (note 11)	**(1,127,988)**	2,504,176
	(13,534,463)	(11,409,603)
Net increase (decrease) in cash during the year	**35,844**	(3,711,229)
Cash, beginning of the year	**8,674**	3,719,903
Cash, end of the year	**$ 44,518**	$ 8,674

See accompanying notes to the financial statements.

1. NATURE OF OPERATIONS

The Company was incorporated on September 18, 1972 in the Province of British Columbia and was continued under the Alberta Business Corporations Act on November 26, 2002. The Company is in the business of exploration for and production of petroleum and natural gas.

2. SIGNIFICANT ACCOUNTING POLICIES

(a) Petroleum and natural gas properties

Capitalized costs

The Company follows the full cost method of accounting, whereby all costs associated with the exploration for and development of petroleum and natural gas reserves are capitalized in a single Canadian cost centre. Such amounts include land acquisition costs, geological and geophysical expenditures, carrying charges of non-producing properties, costs of drilling productive and non-productive wells, site restoration and abandonment costs and administrative costs related to exploration and development activities.

Proceeds from the sale of properties are applied against capitalized costs and gains or losses are not recognized in the statement of operations unless the depletion and depreciation rate would be changed by 20% or more.

Impairment test

The Company calculates a ceiling test whereby the carrying value of its property and equipment is compared at each reporting period end to an estimate of undiscounted future net cash flow from the production of gross proved reserves plus the cost of unproved properties and major development projects, net of impairments, excluded from depletion. Net cash flow is estimated using forecast prices, less estimated costs directly associated with the development, production and sale of reserves. Should the ceiling test result in an excess of carrying value, the Company would then measure the amount of impairment by comparing the carrying amounts of property and equipment to an amount equal to the estimated net present value of future cash flows from proved plus probable reserves and the carrying value of unproved properties, net of impairments. A risk-free interest rate is used to arrive at the net present value of the future cash flows. Any excess is recorded as a permanent impairment. Undeveloped and unproved properties are also assessed periodically to determine whether impairment has occurred.

Depletion and depreciation

The capitalized costs of petroleum and natural gas properties plus future development costs, if any, are depleted and depreciated using the unit-of-production method based on the Company's interest in proved reserves of petroleum and natural gas calculated before royalties. Estimated proved reserves are based on reports prepared by independent engineering consultants. Petroleum substances are converted to volumes of energy equivalent barrels of oil at a conversion rate of six thousand cubic feet ("mcf") of natural gas to one barrel of crude oil.

Costs associated with the acquisition and evaluation of significant unproved properties where there is no commercial production are excluded from amounts subject to depletion and depreciation until such time as the properties are proved or become impaired.

(b) Asset retirement obligation

The Company recognizes and measures the liabilities for obligations associated with the retirement of petroleum and natural gas properties when those obligations result from the acquisition, construction, development or normal operation of the asset. The obligation is measured at fair value and the related costs recorded as part of the carrying value of the related asset. Fair value is estimated using the present value of the estimated future cash costs to reclaim and abandon wells and facilities, using the Company's credit-adjusted risk free interest rate. In subsequent periods, the liability is adjusted for the change in present value and any changes in the amount or timing of the underlying future cash flows required for settlement of the obligation with a corresponding charge to depletion, depreciation and accretion. The asset retirement costs included in petroleum and natural gas costs are depleted or amortized into income in accordance with the Company's policies pertaining to those assets.

(c) Interests in joint ventures

Substantially all of the Company's petroleum and natural gas exploration and development activities are conducted jointly with others and, accordingly, the financial statements reflect only the Company's proportionate interest in such activities.

(d) Future income taxes

The Company uses the liability method for accounting for future income taxes. Under the liability method, future income tax assets and liabilities are determined based on "temporary differences" (differences between the accounting basis and the tax basis of the assets and liabilities), and are measured using the currently enacted tax rates and laws expected to apply when those temporary differences reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in net income in the period when the change is substantially enacted. A valuation allowance is recorded against any future income tax assets if it is more likely than not that the asset will not be realized.

(e) Flow-through shares

Resource expenditure deductions funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. To recognize the foregone tax benefits to the Company, the future income tax liability and the carrying value of the shares issued are adjusted by the effect of the tax benefits renounced to subscribers in the period when the corresponding exploration and development expenditures are renounced.

(f) Stock-based compensation

The Company follows the fair value method to record the compensation expense for stock options granted under its stock option plan. Under this method, the Company estimates the fair value of stock options using the Black-Scholes option pricing model on the date of granting. Based on the value of the option granted, stock-based compensation expense and an offsetting credit to contributed surplus is recorded over the vesting period. When options are exercised, the amortized portion of the value of the option is transferred from the contributed surplus account to the share capital account.

With approval from the Board of Directors, the Company's stock option plan provides that option holders may exercise their right to take a cash settlement payment for the in-the-money value of the option on the exercise date. Should such a right be exercised by the option holder, the amortized portion of the original value of the option is reversed from the contributed surplus account to the extent of the cash settlement payment made to the option holder.

(g) Revenue recognition

Revenue from the production of petroleum and natural gas is recognized when deliveries of products are made to third parties.

(h) Use of estimates

Management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reported period. The amounts recorded for depletion and depreciation of petroleum and natural gas properties and the provision for the asset retirement obligation and the ceiling test are based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. The fair value of stock options and the related stock-based compensation expense is based on estimates using the Black-Scholes option pricing model. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be significant.

(i) Net income per share

Diluted per share amounts are calculated using the treasury stock method. Diluted calculations reflect the incremental common shares that would be issued upon exercise of dilutive options, warrants and equivalents assuming the proceeds would be used to repurchase shares at average market prices for the period. Anti-dilutive items are not included in the calculation.

(j) Financial instruments

Effective January 1, 2007, the Company adopted the Canadian Institute of Chartered Accountants ("CICA") accounting standards in respect of Financial Instruments – Recognition and Measurement, Hedges, Comprehensive Income and Financial Instruments - Disclosure and Presentation. These accounting standards require the classification of all financial instruments by category: loans and receivables, held to maturity investments, available for sale financial assets, held for trading assets or other liabilities. The standards prescribe criteria for the recognition of certain derivative financial instruments. As well, the standards prescribe the measurement basis, either amortized cost or fair value, of the specified classes of financial instruments subsequent to their initial recognition; the timing and recognition of realized and unrealized gains and losses on financial instruments in net income or other comprehensive income; and disclosures, including a new category of shareholders' equity called accumulated other comprehensive income. In accordance with transitional provisions in the standards, these accounting policies were adopted on a prospective basis with no restatement of prior period financial statements.

Application of the standards to the classification and measurement of the Company's financial instruments did not have any impact on net income in 2007. The Company did not recognize any items affecting other comprehensive income or accumulated other comprehensive income on adoption of the standards for the year ended December 31, 2007.

(k) Accounting changes

The Company adopted the revised accounting standard of the CICA concerning Accounting Changes effective January 1, 2007. The new standard permits voluntary changes in accounting policy only if they result in financial statements which provide more reliable and relevant information. Accounting

policy changes are applied retrospectively, unless it is impractical to determine the period and cumulative impact of the change. Corrections of prior period errors are applied retroactively, and changes in accounting estimates are applied prospectively by including these changes in earnings. No accounting policy changes were adopted or prior period corrections were made in 2007.

3. PROPERTY AND EQUIPMENT

	December 31, 2007		
	Cost	**Accumulated Depletion and Depreciation**	**Net**
Petroleum and natural gas properties	**$30,732,339**	**$ 5,815,284**	**$24,917,055**

	December 31, 2006		
	Cost	Accumulated Depletion and Depreciation	Net
Petroleum and natural gas properties	$ 18,010,747	$ 1,608,259	$ 16,402,488

In conducting the ceiling test as at December 31, 2007, the Company's estimated future cash flows exceeded the carrying value of the related petroleum and natural gas properties, after using certain assumptions pertaining to future commodity prices. Assumptions for crude oil and natural gas sales prices at the wellhead in Canadian dollars are consistent with the Company's December 31, 2007 reserve report as provided by GLJ Petroleum Consultants and are detailed below:

	Oil ($/barrel)	**Gas ($/mcf)**
2008	$ 86.33	$ 6.43
2009	82.33	7.20
2010	78.33	7.24
2011	76.33	7.25
2012	76.33	7.25
Thereafter	76.33 – 83.55	7.25 – 8.76

During the year ended December 31, 2007, the Company has capitalized general and administrative costs of $184,974 (December 31, 2006 – $185,014) and interest in the amount of $nil (December 31, 2006 – $nil).

An estimated future capital cost of $7,647,000 (December 31, 2006 – $7,736,000), required for properties to which proved reserves have been attributed, has been added to property and equipment costs for depletion and depreciation purposes. Costs relating to unproved properties of $2,220,092 (December 31, 2006 – $5,191,878), including $nil (December 31, 2006 – $3,012,191) of facilities and infrastructure pertaining to future development projects anticipated to be completed subsequent to year-end, have been excluded from property and equipment costs for depletion and depreciation purposes.

4. ASSET RETIREMENT OBLIGATION

	Year ended December 31 2007	Year ended December 31 2006
Asset retirement obligation, beginning of the year	**$ 323,037**	$ 113,140
Incurred in the year	**315,117**	208,184
Expenditures made on asset retirements	**(25,900)**	(8,240)
Change in present value during period	**54,125**	9,953
Asset retirement obligation, end of the year	**$ 666,379**	$ 323,037

The total undiscounted amount of cash flows required to settle the obligations as measured at December 31, 2007 is estimated to be $951,555 (December 31, 2006 - $869,910). These obligations are expected to be settled at various times over the 16 years subsequent to December 31, 2007. The credit-adjusted risk free rate at which the estimated cash flows were discounted was 7.75% during the year ended December 31, 2007 (December 31, 2006 – 8%) and the estimated inflation rate used to project future costs was 1.5% (December 31, 2006 – 1.5%).

5. INCOME TAXES

	Year ended December 31 2007	Year ended December 31 2006
Statutory tax rate	**33.87%**	32.12%
Anticipated tax expense (recovery)	**$ (360,082)**	$ (307,732)
Increase (decrease) resulting from:		
Non-deductible stock-based compensation	**121,057**	178,468
Tax rate changes	**(12,516)**	(60,344)
Other	**557**	(35,641)
Future tax expense (recovery)	**$ (250,984)**	$ (225,249)

The components of the net future tax liability are as follows:

	December 31 2007	December 31 2006
Future income tax assets related to:		
Non-capital losses	**$ 66,547**	$ 103,530
Asset retirement obligations	**203,246**	103,759
Share issue costs	**21,143**	29,006
Total future income tax assets	**290,936**	236,295
Future income tax liabilities related to:		
Property and equipment	**(1,483,375)**	(1,024,996)
Future income tax asset (liability)	**$ (1,192,439)**	$ (788,701)

Pursuant to the Company's issue of common shares on a flow-through basis in 2007, the Company has committed to renounce to investors qualifying expenditures of $2,175,000 to be incurred prior to December 31, 2008. As at December 31, 2007, the Company has remaining commitments to incur $1,165,140 of qualifying expenditures prior to December 31, 2008.

6. SHARE CAPITAL

The Company has authorized unlimited common shares and unlimited first preferred shares. The outstanding share capital is as follows:

(a) Common Shares

	Year ended December 31, 2007	
	Number	**Amount**
Balance, beginning of the year	**17,067,392**	**$14,093,637**
Issued during the year	**1,812,500**	**3,625,000**
Issued on a flow-through basis during the year	**906,250**	**2,175,000**
Shares issued on exercise of stock options	**31,667**	**21,517**
Shares repurchased under normal course issuer bid at average stated capital price per share	**(341,000)**	**(344,410)**
Share issue costs	**–**	**(28,372)**
Tax effect of flow-through shares issued	**–**	**(663,375)**
Tax effect of share issue costs	**–**	**8,653**
Balance, end of the year	**19,476,809**	**$18,887,650**

	Year ended December 31, 2006	
	Number	Amount
Balance, beginning of the year	14,871,558	$ 9,620,765
Issued during the year	1,495,834	3,204,833
Issued on a flow-through basis during the year	700,000	1,925,000
Share issue costs	–	(56,940)
Tax effect of flow-through shares issued	–	(618,310)
Tax effect of share issue costs	–	18,289
Balance, end of the year	17,067,392	$ 14,093,637

At December 31, 2007, the Company is holding 7,049 common shares in escrow arising from an agreement that provides for a release subject to approval by regulatory authorities.

(b) Normal Course Issuer Bid

Effective April 1, 2007, the Company implemented a normal course issuer bid whereby it could acquire within one year of the effective date up to 10% of the estimated public float of its outstanding common shares, which was estimated to be 1,236,869 shares. During the year, the Company acquired 341,000 at an average cost of $1.60 per share.

(c) Stock Options

Under the Company's stock option plan, common share purchase options may be granted to directors, officers, staff and consultants. The Company may grant options to purchase common shares up to a maximum of 10% of the number of issued and outstanding common shares. The granted common share purchase options are subject to vesting requirements as determined upon granting and are subject to expiry five years following the date granted.

	Year ended December 31, 2007			Year ended December 31, 2006		
	Number Outstanding		**Weighted Avg Price Per Share**	Number Outstanding		Weighted Avg Price Per Share
Balance, beginning of the year	**1,651,666**	**$**	**1.244**	1,483,500	$	0.884
Granted during the year	**210,500**		**1.473**	264,000		2.946
Exercised during the year	**(31,667)**		**0.331**	(95,834)		0.348
Cancelled during the year	**(222,999)**		**1.077**			
Balance, end of the year	**1,607,500**	**$**	**1.229**	1,651,666	$	1.244
Exercisable, end of the year	**1,045,112**	**$**	**0.961**	718,666	$	0.675

The following table summarizes information about the Company's stock options outstanding:

	December 31, 2007			December 31, 2006		
Exercise Price	**Options Outstanding**	**Amounts Vested**	**Remaining Contractual Life (Years)**	Options Outstanding	Amounts Vested	Remaining Contractual Life (Years)
$0.225	**300,000**	**300,000**	**1.0**	360,000	360,000	2.0
0.370	**200,000**	**200,000**	**1.1**	200,000	133,333	2.1
0.380	**178,334**	**118,888**	**2.1**	207,666	18,666	3.1
1.280	**105,500**	**-**	**4.9**			
1.300	**50,000**	**-**	**5.0**			
1.680	**515,000**	**343,334**	**2.5**	615,000	205,000	3.5
2.000	**15,000**	**-**	**4.4**			
2.070	**5,000**	**3,333**	**2.9**	5,000	1,667	3.9
2.860	**12,500**	**4,167**	**3.4**	12,500	–	4.4
2.950	**226,166**	**75,390**	**3.4**	251,500	–	4.4

Assumptions used in the calculation of the weighted average fair value of options granted are as follows:

Year ended		**December 31 2007**		December 31 2006
Options granted during the year		**210,500**		264,000
Risk-free interest rate		**4.0%**		5.0%
Expected life		**5 years**		5 years
Average volatility		**29%**		80%
Anticipated dividends		**none**		none
Weighted-average fair value per option	**$**	**0.52**	$	1.98

(d) Contributed Surplus

	Year ended December 31 2007	Year ended December 31 2006
Contributed surplus, beginning of the year	**$ 854,156**	$ 320,044
Stock-based compensation charged during the year	**357,416**	555,628
Reversal of amortized portion of the option value on exercise of option holder right to a cash payment	**(4,500)**	
Normal course issuer bid excess purchase price over stated capital	**(202,235)**	
Amounts transferred to share capital on exercise of options	**(11,033)**	(21,516)
Contributed surplus, end of the year	**$ 993,804**	$ 854,156

7. PER SHARE AMOUNTS

Basic per share amounts are calculated using the weighted average number of common shares outstanding during the year ended December 31, 2007 of 19,411,224 (year ended December 31, 2006 – 16,346,171).

Options to purchase 1,607,500 common shares were outstanding at December 31, 2007 (1,651,666 – December 31, 2006), 622,904 of which were potentially dilutive (year ended December 31, 2006 – 1,387,666) and which have not been included in the computation of earnings per share as the effect would be anti-dilutive.

The following table sets forth the details of the denominator used for the computation of basic and diluted earnings per share:

	Year ended December 31 2007	Year ended December 31 2006
Basic weighted average number of common shares	**19,411,224**	16,346,171
Net effect of dilutive securities		
Stock options	-	–
Diluted weighted average number of common shares	**19,411,224**	16,346,171

8. RELATED PARTY TRANSACTIONS

(a) Management Agreement

The Company is subject to a management agreement with Grizzly Resources Ltd. ("Grizzly"), a company related by virtue of common management. Under the agreement Grizzly provides technical and administrative services, which are in the normal course of business and are recorded at the exchange amount which is the amount of consideration established and agreed to by the related parties. The contract charges the Company for services based on a fee for units of production and a percentage of capital expenditures.

	Year ended December 31 2007	Year ended December 31 2006
Management fees	**$ 538,453**	$ 297,436
Less amounts capitalized	**(184,974)**	(185,014)
Management fees expensed	**$ 353,479**	$ 112,422

As at December 31, 2007, $140,302 (December 31, 2006 – $76,878) related to these services was included in accounts payable and accrued liabilities.

(b) Joint Venture Operator

The joint venture operator of the majority of the petroleum and natural gas properties owned by the Company is Grizzly. As operator, in accordance with industry standards for joint interest billings, Grizzly charged $211,496 (2006 – $176,918) in overhead administration, of which $137,039 (2006 - $160,650) was capitalized as property and equipment costs.

(c) Overriding Royalty

Until January 15, 2007, the Company was subject to an overriding royalty agreement with a member of the Company's Board of Directors on one of the Company's operating areas. The agreement provided for a 2% overriding royalty on revenue earned within the area. During the year, $nil (2006 – $29,457) was paid in royalties under this contract. As at December 31, 2007, $nil (2006 - $19,052) related to unpaid royalties under this contract was included in accounts payable and accrued liabilities.

On January 15, 2007, the Company acquired this overriding royalty payable to a member of the Company's Board of Directors, for a price not to exceed $550,000. The Company paid $250,000 on the acquisition date, and is obligated to pay the balance of the consideration upon the Company obtaining title to certain additional lands within the area subject to the royalty.

(d) Consulting Fees

During the year, the Company paid consulting fees in the amount of $72,000 to a member of the Board of Directors. At year-end, $6,000 remained in accounts payable and accrued liabilities.

9. REVOLVING PRODUCTION BANK LOAN

	Year ended December 31 2007	Year ended December 31 2006
Balance, beginning of year	**$ 1,806,000**	$ –
Amounts advanced, net of repayments	**5,087,808**	1,806,000
Balance, end of year	**$ 6,893,808**	$ 1,806,000

At year-end, the Company had a revolving production bank loan facility available to a maximum of $8,000,000 with a Canadian bank (2006 - $6,000,000). The outstanding loan balance under this facility bears interest at the bank's prime rate per annum. On February 8, 2008, the Company's bank provided an additional revolving term loan facility in the amount of $4 million to provide development capital for drilling and equipping operations at its principal producing property. Interest on loan draws under this incremental facility is charged at the annual rate of bank prime plus 1%. The bank loan facilities are secured by a general security agreement and demand debenture providing a first floating charge over all present and after acquired property of the Company.

10. FINANCIAL INSTRUMENTS

(a) Classification and measurement

The Company's financial assets and liabilities are classified and measured as follows:
- Cash and cash equivalents are classified as held for trading and are measured at fair value.
- Accounts receivable are classified as loans and receivables and are initially measured at fair value, and subsequently at amortized cost using the effective interest rate method, which approximates fair value.
- Accounts payable, accrued liabilities and bank loan payable are classified as other liabilities and are initially measured at fair value, and subsequently at amortized cost using the effective interest rate method, which approximates fair value.

Gains and losses related to periodical revaluations are recorded in net income.

(b) Credit risk

The majority of the accounts receivable are in respect of oil and natural gas operations. The Company generally extends unsecured credit to these customers, and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions. Management believes the risk is mitigated by the size and reputation of the companies to which they extend credit. The Company has not experienced any credit loss in the collection of receivables to date.

(c) Interest rate risk

The Company is exposed to the risk of interest rate fluctuations on the amounts drawn on its revolving production bank loan. The outstanding loan balance bears interest that is based on the bank's prime rate or a factor based on the bank's prime rate.

(d) Commodity price, foreign exchange rate and interest rate risk

The nature of the company's operations results in exposure to fluctuation in commodity prices, foreign exchange rates and interest rates. Derivative financial instruments may be used by the Company to reduce its exposure to fluctuations in commodity prices, foreign exchange rates and interest rates. All derivative instruments, including embedded derivatives, are recorded at fair value. All changes in fair value are included in net income unless effective hedge accounting is used, in which case changes in fair value are recorded in other comprehensive income.

The Company entered into a costless collar natural gas sales contract, effective November 1, 2006 to March 31, 2007. The collar contract provided the Company with a floor sales price of $8.00 per gigajoule (GJ) and a ceiling of $11.10 per GJ of natural gas on 625 GJ per day during the period. Effective from April 1, 2007 to March 31, 2008, the Company entered into another costless collar natural gas sales contract with a floor price of $7.00 per GJ and a ceiling of $9.42 per GJ on 1,000 GJ per day throughout the contract period. The unrealized gain from these embedded derivatives has been included in accounts receivable and revenue accordingly.

	Year ended December 31 2007	Year ended December 31 2006
Amounts collected (paid) as a result of contracts during the year	**$ 380,585**	$ 36,318
Unrealized gain on contract at year-end	**49,704**	90,000
Net increase (reduction) to revenue from contracts during the year	**$ 430,289**	$ 126,318

11. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	Year ended December 31 2007	Year ended December 31 2006
Changes in non-cash working capital		
Accounts receivable	**$ (435,025)**	$ (351,443)
Prepaid expenses	**(8,677)**	(12,854)
Accounts payable and accrued liabilities	**(962,291)**	2,659,742
Total changes in non-cash working capital	**(1,405,993)**	2,295,445
Less changes in non-cash working capital from investing	**1,127,988**	(2,504,176)
Changes in non-cash working capital from operations	**$ (278,005)**	$ (208,731)

12. SUBSEQUENT EVENTS

(a) Normal Course Issuer Bid

After the year-end, the Company acquired an additional 25,900 shares for $33,020 pursuant to its normal course issue bid. Due to restrictions on the use of funds drawn under the Company's bank loan facilities, further purchases made under the normal course issuer bid were suspended in February 2008.

(b) Commodity Price Hedging

Since December 31, 2007, the Company has entered into three commodity price hedge contracts. On February 7, 2008, it entered into a fixed price physical natural gas sale from April 1, 2008 to October 31, 2008 on 2000 GJ per day at $7.05 per GJ. Thereafter, the Company entered into two costless collar physical natural gas sales from November 1, 2008 to March 31, 2009. One contract is for 1,000 GJ per day based on a floor price of $7.75 per GJ and a ceiling price of $9.45 per GJ and the other contract is for 500 GJ per day based on a floor price of $8.00 per GJ and a ceiling price of $10.00 per GJ.

13. FUTURE ACCOUNTING POLICY CHANGES

(a) Financial Instruments

In 2008, the Company will be required to adopt updated CICA pronouncements regarding Financial Instruments – Disclosures and Financial Instruments – Presentation. These new accounting standards replace the current accounting standard on Financial Instruments – Presentation and Disclosure that was adopted by the Company in 2007. The Company anticipates that the main impact to its financial statements will be in terms of additional disclosures required with respect to the significance of financial instruments on its financial position and performance; qualitative and quantitative information about its exposure to risks arising from financial instruments; and management's objectives, policies and processes for managing such risks.

(b) Capital Disclosures

In 2008, the Company will be required to disclose information about its objectives, policies and processes for managing capital.

(c) Going Concern

The Company will be required to provide additional disclosures, beginning in 2008, with respect to management's assessment of the Company's ability to continue as a going concern. The Company does not anticipate any impact to its financial statements arising from adoption of this new accounting standard.

(d) Convergence with International Financial Reporting Standards

The CICA has recently announced the convergence of Canadian generally accepted accounting principles with International Financial Reporting Standards effective January 1, 2011. While specific requirements of the transition continue to be under review by the CICA, management is currently unable to assess the impact on the Company's financial statements.

BOARD OF DIRECTORS AND MANAGEMENT

Directors

Larry J. Parks, Chairman
Blaine C. Favel
Jeff Lawson
Gerry C. Quinn
James K. Wilson

Officers

Larry Parks, President & Chief Executive Officer
Rob Solinger, VP Finance & Chief Financial Officer
Bill Manley, VP Engineering & Operations
Cam Weston, VP Land
Al Williams, VP Exploration
Jim Wilson, VP & Corporate Secretary

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